COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
FOURTH SET OF INFORMATION REQUESTS FROM THE D.T.E.
D. T. E. 05-27

Date: June 30, 2005

Responsible: Lawrence R. Kaufmann, Consultant (PBR)

DTE-4-14 Refer to Exh.BSG/LRK-2, at 7. Please explain the following sentence: “Because it was necessary for O&M costs to be defined comparably over this entire period to undertake an “apples to apples” O&M cost trend comparison, O&M costs associated with the LDAC tracker mechanism for 2002 and 2003 were netted out of those years.”

Response: Please see the response to DTE-4-1.

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Responsible: Lawrence R. Kaufmann, Consultant (PBR)

DTE-4-16 Referring to the econometric cost model, please:
(a) discuss what the Company used the model for;
(b) show that the model estimation techniques follow standard econometric practice in estimating the parameters of an econometric cost model. Please provide copies of any published articles, papers, reports, or book chapters in support of your answer;
(c) show that the model selection techniques follow standard econometric practice in selecting variables for inclusion in an econometric cost model (i.e., having two quantity variables in the cost function). Provide copies of any published articles, papers, reports, or book chapters in support of your answer;
(d) justify the selection (advantages and disadvantages) of the a translog functional form (instead of other potential functional forms such as Cobb-Douglas or any of the Generalized Leontief cost functions) in view of the goal of the Company (keep in mind you answer in part A of this question);
(e) indicate whether the Company has tried to fit a different functional cost function. If yes, please present all workpaper, and supporting documentation. If not, why not?

Response:

a) The model was used to evaluate Bay State's O&M cost performance.

b) We estimate our model using a system of equations based on the cost function and its associated share equations. We use the seemingly unrelated regression (SUR) method to estimate this system of equations. This estimation approach is well established in the literature; a standard reference is W. H. Greene (2000), Econometric Analysis, Prentice Hall: New Jersey, pp. 614-620. Copies of the relevant sections from Greene's textbook are attached as Attachment DTE-4-16(a).

c) This model selection technique, with two quantity variables in the cost function, follows standard econometric cost development for multiproduct firms. Utilities are widely viewed as multiproduct firms, and this has been recognized in previous Department decisions. For example, the total factor productivity (TFP) study presented by Boston Gas in DPU 96-50 measured gas distribution output by the total number of customers served. The Department was critical of this specification and concluded that, by not including volumes as an output, it may have under-estimated the growth in gas distributors' output. Accordingly, when PEG updated the TFP study in DTE 03-40, it included customer numbers and throughput as outputs in both the TFP and econometric cost studies.

Examples of cost function specifications for multiproduct firms that include two outputs are Kim, H.Y., 1987, "Economies of Scale in Multi-Product Firms: An Empirical Analysis," *Economica,* 54 (214): 185-206; and Caves, D.W., L.R. Christensen and M.W. Tretheway, 1980, "Flexible Cost Functions for Multiproduct Firms, *The Review of Economics and Statistics*, 62 (3): 477-481. Copies of these articles are provided at Attachment DTE-4-16(b).

d) We use the model to evaluate Bay State's O&M cost efficiency given the business conditions that it faces. Because the gas distribution industry is characterized by economies of scale, it is important for the functional form to reflect potential economies of scale relationships between cost and different gas distribution outputs. More generally, it is desirable for the functional form to place as few restrictions as possible on the assumed, underlying technology that relates cost to various cost "drivers."

The translog cost function is a second-order approximation to any underlying cost function. As such, it is extremely flexible and does not restrict the underlying technological relationships that may be reflected in the sample data. More concretely, the translog functional form includes square terms on each output, which allows economies of scale to be reflected in the estimated cost function coefficients, and interaction terms between different outputs and between outputs and input prices, which allows the impact of cost drivers to depend not only on the "direct" relationship between cost and a specific cost driver variable, but also on how those cost driver variables interact. Overall, this allows a rich array of scale effects and factor substitutions to be reflected in the estimated cost function coefficients.

The Cobb-Douglas functional form typically does not allow interaction or scale effects to be estimated reliably. The Generalized Leontief, like the translog, is a "flexible form" cost function, but some research shows that it is not as reliable as the translog, particularly with respect to estimating economies of scale. In gas distribution cost research, it is critical for economies of scale be estimated reliably.

Guilkey, Lovell and Sickles compared the translog (TL), generalized Leontief (GL), and generalized Cobb-Douglas in their 1983 article "A Comparison of the Performance of Three Flexible Functional Forms" (*International Economic Review*, 24 (3): 591-616). Their conclusion was that "our effort to turn up a flexible form more reliable than the TL form must be considered a failure. In almost every comparison we have conducted the TL systems estimator…outperform(s) all other estimators, typically by a wide margin. The GL form is a distant third in all comparisons (except those in which the true partial elasticities of substitution are small and positive)." A copy of this article is attached as Attachment DTE-4-16(c).

e) Given the conclusion cited above that the translog "outperforms all other estimators, typically by a wide margin," we have not tried to fit a different cost function.

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Responsible: Lawrence R. Kaufmann, Consultant (PBR)

DTE-4-25 Refer to Exh. BSG/LRK-2. Please discuss any data or other limitations that affected the sample selection process for the econometric cost study. How did the Company address these limitations?

Response: The selected sample was identical to that used in the study for Boston Gas in DTE 03-40, except that Bay State itself was added. Data for Bay State are equivalent to data Bay State has provided in annual reports to the Department, with the exception of the adjustments to the Company's O&M data that were explained in DTE-4-1.

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Date: June 30, 2005

Responsible: Lawrence R. Kaufmann, Consultant (PBR)

DTE-4-29 Refer to Exh. BSG/LRK-1, at 8-10. Please:
(a) indicate the most recent year for which data are available to update the Boston Gas Company productivity study in D.T.E. 03-40;
(b) explain why, given the Department policy "to rely on the most recent information available" in the conduct of a productivity study (see, D.T.E. 03-40, at 477), the Company did not update the Boston Gas Company productivity study to include data up to the year closest to the test year for the Company's rate case filing;
(c) indicate the time period covered by the Boston Gas Company productivity study in D.T.E. 03-40. Given the time period covered by the Boston Gas Company productivity study, indicate how "old" the study was by the time the Company filed its rate case in this proceeding;
(d) discuss whether the appropriateness of using the results of the Boston Gas Company productivity study in D.T.E. 03-40 in the instant proceeding should be determined by the time period covered by the Boston Gas Company productivity study, or by the time since the issuance of the Department Order in D.T.E. 03-40.

Response:

(a) The productivity study in DTE 03-40 requires data on TFP trends for the Northeast gas distribution industry and the US economy. The latter are developed by the US Bureau of Labor Statistics (BLS). The most recent estimates on multifactor productivity (MFP) growth published by the BLS are for 2002. Therefore 2002 is the most recent year for which data are available to update the TFP study presented in DTE 03-40.

(b) As discussed in DTE 01-56 for Berkshire Gas, it is also Department policy that utilities should not have to update TFP studies if "the cost to conduct the study would likely outweigh any benefits of the study" (DTE 01-56) at 21). The rationale developed by the Department in DTE 01-56 applies at least as strongly to Bay State's PBR proposal as it did for Berkshire's. In the Berkshire case, the Department relied on a value for the productivity offset that was approved more than five years earlier, whereas the Boston Gas PBR plan was approved less than eighteen months before Bay State's plan was filed. The productivity update in DTE 03-40 also responded to, and rectified, the Department's concerns regarding the "accuracy" of the productivity study submitted in Boston Gas's original PBR application (DPU 96-

50). The productivity offset in DTE 03-40 is therefore more accurate and more current than what was approved for Berkshire Gas in DTE 01-56, and Bay State has less ability to improve the accuracy of this productivity offset than Berkshire Gas did at the time DTE 01-56 was approved.

In addition, because US government data on US MFP growth are only available through 2002, it is currently possible to add only a single year to the sample period of 1990-2001 used to estimate the TFP differential in DTE 03-40. The current TFP differential is therefore computed using 11 years of measured productivity changes; adding all available new data would make the TFP differential equal to the average of 12 years of measured productivity changes. This single year of data is likely to have little material impact on the average for the TFP differential, but Bay State would incur significant costs to update the industry’s measured TFP trend.

(c) The sample period for the Boston Gas productivity study in DTE 03-40 was 1990-2001. The end-period for the study was just over three years before Bay State filed its rate case, which would make it three years “old” according to the suggested interpretation. Updating the study would make it two years “old.” In contrast, when the Department ruled that the costs to Berkshire Gas of updating the extant TFP study outweighed the benefits, the sample period for the extant study was 1984-1994. Berkshire apparently filed its application in 2001, which would make the TFP study in that case six years “old.”

(d) In the instant proceeding, the appropriateness of using the results of the Boston Gas productivity study in DTE 03-40 should be determined by the time since the issuance of the Department Order in DTE 03-40. The elapsed time since that Order corresponds much more closely to the number of sample years that can be added to the database. For example, it has been approximately 19 months since the Order in DTE 03-40, and since that time it has become possible to add a single year’s worth of data to the estimate of the TFP differential. Focusing on the three year gap between the end of the last study and the time Bay State’s rate case was filed gives a misleading impression of the amount of new information that is potentially available. Moreover, both the costs and benefits that result from updating TFP studies depend greatly on the number of new sample years which, as discussed, are more closely related to the time since the Order in DTE 03-40 was issued than to the end-date of the most recent TFP study. The time period since the Order was issued therefore has a stronger relationship to the costs and benefits that the Department has said should be evaluated when determining if a TFP study should be updated.

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Date: June 30, 2005

Responsible: Lawrence R. Kaufmann, Consultant (PBR)

DTE-4-42 Refer to Exh. BSG/LRK-1, at 11-12. Please discuss the likely benefits of the proposed PBR plan to the Company's ratepayers and shareholders compared to traditional cost of service regulation. In particular, demonstrate that ratepayers are not likely to pay more under the proposed PBR plan than they would have under a traditional cost of service regulation.

Response:

In Docket No. 94-158, the Department examined the merits of incentive regulation (also referred to as performance-based regulation in the docket) and cost of service/rate of return (COS/ROR) regulation as alternative means for advancing its traditional goals of safe, reliable and least-cost energy service and for promoting the objectives of economic efficiency, cost control, lower rates and reduced administrative burdens. The Department noted that

> the defects of traditional COS/ROR regulation are well known. The "cost plus" approach under COS/ROR regulation contributes to (1) lack of incentive for cost control, through its inherent bias favoring expenditures which can be passed through to customers; (2) inflexible and less than efficient pricing; (3) persistent cross-subsidies among service classifications; (4) inefficient allocation of resources; (5) poor asset management; (6) risk-averse management; and (7) disincentives for innovation. COS/ROR is also a costly method of regulation, and is characterized by long lags both in reflecting and controlling actual utility operations and their costs. (p. 9)

A regulatory system with these properties clearly reduces incentives to operate efficiently. Inefficiency leads, in turn, to a less than optimal provision of utility services and frustrates the goal of providing energy services at the least cost. Obviously, it is impossible for energy services to be provided at the least cost if the regulatory system restricts managers' incentive and ability to operate at the lowest possible cost. The Department has found that these incentives are lacking under traditional COS/ROR.

Compared with cost of service regulation, the Department concluded that "five broad classes of potential benefits are associated with incentive regulation: improved X-efficiency; improved allocative efficiency; improved dynamic efficiency; facilitation of new services; and reduced administrative costs." (pp. 52-53). X efficiency refers to the ability to operate as cost effectively as possible, given the available technology. The Department refers to allocative efficiency as "the ability to provide service using the optimal combination of inputs, thereby minimizing total cost." (p. 53). This is indeed one manifestation of allocative efficiency, but another is the ability to price utility services as efficiently as possible. For example, allocatively efficient prices would not reflect cross subsidies between service classes and could be adjusted to reflect changes in customers' competitive opportunities. Dynamic efficiency refers to utilities' longer-run investment behavior and reflects efficiencies related to research, reorganization and capital equipment choices. Because it is focused on the longer run, dynamic efficiency is also related to innovation and the provision of new services.

As stated in the Department's Order in DTE 03-40, "a company seeking approval of an incentive proposal is required to demonstrate that its approach is more likely than current (cost of service) regulation to advance the Department's traditional goals of sate, reliable and least-cost energy service and to promote the objectives of economic efficiency, cost control, lower rates, and reduced administrative burden in regulation" (DTE 03-40 at 471). Although a Company is not explicitly required to show that its incentive proposal complies with Department precedent, any proposal that is consistent with PBR plans the Department approved in the past is clearly more likely to satisfy the Department's requirements.

Bay State's price cap proposal meets the Department's standard of review for incentive ratemaking and will promote the Department's goals and each of the five broad classes of benefits more effectively than cost of service regulation. The Company's proposal promotes "X efficiency" since its price cap formula sets allowed prices on the basis of external inflation measures and data on industry TFP and input price trends. The calibration of this formula creates a proxy for how prices would evolve in a competitive industry, where prices depend on industry-wide developments in input prices and TFP rather than on the costs of any individual firm. Since Bay State's price changes are linked to the price cap index (PCI) rather than its own unit costs, the Company is effectively "competing" against the PCI, and any unit cost reductions it can achieve improve its bottom line. This is not the case under COS/ROR, where unit cost reductions can be translated in short order into price reductions. Setting prices on the basis of a competitive market proxy therefore creates optimal incentives to control unit cost.

In addition, Bay State will have much stronger incentives for allocative efficiency under its price cap proposal than under COS/ROR. Again, prices depend on external data rather than the Company's own costs and spending decisions, so Bay State has incentives to pursue any and all changes in its input mix that can reduce cost. For example, the Company will have optimal incentives on choosing between outsourcing or undertaking activities "in house." This is not necessarily the case under cost of service regulation. Some economists believe that input mix decisions are distorted under COS/ROR. In particular, it is argued that COS/ROR creates incentives for excessive substitution of capital for other inputs.

Bay State also has more ability and stronger incentives to price efficiently under its proposal. The Company's price cap proposal creates some flexibility to adjust its relative prices subject to a cap on overall price inflation and to respond to competitive market developments (*e.g.* for conversions of customers using home heating oil rather than natural gas). This type of pricing flexibility is rare in cost of service regulation, where tariffs can typically only be changed after a cumbersome regulatory review. The Company's price cap proposal therefore facilitates the ability to retain and attract natural gas customers, thereby spreading fixed costs over a larger output base and promoting productivity growth. A number of economists have also shown that, theoretically, price cap regulation promotes allocatively efficient price structures.[1]

The Company's price cap proposal will also entail lower regulatory costs compared with cost of service regulation. The dichotomy of regulatory burdens under COS/ROR and PBR is manifest even in the current Bay State filing. Far more witnesses, testimony, exhibits, and discovery are associated with the cost of service portion of this case than with the PBR portion. This dichotomy is even more striking when it is recognized that the cost of service filing is associated with setting rates for a single year, while the PBR filing establishes index-based rate adjustments for at least the next four years. In addition, the Company's proposal will guarantee that it "stays out" of a rate case proceeding for at least five years. Under cost of service regulation, it is likely that Bay State would have to file one or more additional rate case applications during this period since the reality is that unit costs are rising for Northeast gas distributors. There would naturally be additional, direct costs and administrative burdens associated with these rate case filings. These incremental costs would ultimately be borne by ratepayers. There would also be indirect costs, since additional regulatory filings inevitably shift company attention and the corporate culture towards the regulatory process and away from finding new ways to improve efficiency. This diversion of management attention would further frustrate the goal of least cost supply of energy services. Overall, there is little doubt that the Company's proposal represents a far less burdensome regulatory approach than COS/ROR,

[1] For example, see T. Brennan (1989), "Regulating by Capping Prices," *Journal of Regulatory Economics*, 133-147, and Bradley, I. and C. Price (1988), "The Economic Regulation of Private Industries by Price Constraints," *Journal of Industrial Economics*, 99-106.

and these lighter regulatory burdens can serve to enhance customer benefit.

The Company's proposal is also far more likely to encourage dynamic efficiency and innovation. These incentives are notably lacking in COS/ROR for several related reasons. One is the asymmetry with which innovative practices are treated in cost of service ratemaking. Suppose a company is considering some new, untried practice that has the potential to reduce rates. Under COS/ROR, if the company pursues that practice and it is successful, then the resulting cost reductions can lead in short order to a rate hearing that transfers those gains to customers. On the other hand, if the practice does not prove to be successful, the utility is at risk of a prudence disallowance for the costs of the initiative, since it could have retained the "tried and true" approach. This asymmetry in regulatory treatment can prevent managers from implementing otherwise profitable and efficiency-enhancing programs. This regulatory asymmetry can also adversely affect the corporate culture. Since innovation leads to much lower rewards compared with competitive industries, utility managers have less incentive to look to the marketplace in order to anticipate and respond to their customers' changing needs. This exacerbates the harmful impact on utility corporate cultures due to the greater regulatory burdens of COS/ROR regulation that were discussed above.

The Company's proposal encourages dynamic efficiency in several ways. First, the PBR formula is calibrated using comprehensive performance measures (industry TFP and input price trends). Such a PBR plan creates balanced incentives to pursue all kinds of initiatives that may reduce unit cost. Second, the Company has proposed a multi-year PBR plan. By increasing certainty that gains will be retained for a known period of time, managers can evaluate programs with longer term "payback" horizons, such as those that may entail upfront costs and deliver benefits over a multi-year period. Third, the fact that rates are de-linked from costs during the PBR period dramatically reduces the role and scope of prudence reviews and may encourage the company to undertake initiatives that would be impractical under COS/ROR. All of these factors create a more innovative, efficiency-focused corporate culture that can benefit customers. The Bay State proposal is therefore much more consistent with the following analysis, which appeared in a recently published article examining innovation under different regulatory systems:

> If there is a consensus on thought on the innovation process it is that innovation requires highly motivated individuals willing to go beyond doing what has been tried previously, beyond following standard operating procedures, beyond using time-tested methods and technology. Innovation and discovery of new ways of doing things, new technologies, or new applications based on existing technologies requires companies and individuals to

> question the *status quo*, to be creative, and to be willing to bear the significant risks associated with exploring new methods. Of course, enhanced incentives in the form of meaningful rewards for successful discoveries are required to elicit such effort and risk-bearing.[2]

By providing the "meaningful rewards" that are unlikely under cost of service regulation, the Bay State proposal is far more likely than cost of service regulation to promote dynamic efficiency and innovation.

The potential for gas distributors to exhibit dynamic efficiency, be innovative and introduce new products can perhaps be made more concrete through an example. It should be emphasized that this example is illustrative only and does not imply that Bay State is currently considering such an initiative or would pursue it under PBR. However, it will hopefully demonstrate that certain innovative and creative practices will be much more feasible under PBR than under COS/ROR.

There are currently field demonstrations examining the feasibility of inserting fiber optic lines in "live" gas lines. This could prove to be a much cheaper method of installing the "last mile" of fiber optic networks in urban and suburban areas. The "last mile" installation costs have generally been prohibitively expensive for most end-users but, by using existing infrastructure, installing fiber optics in gas delivery networks could make the extension of the fiber optic network more economically feasible.

Such a project also becomes much more feasible under PBR than COS/ROR. Gas distributors subject to PBR would evaluate the merits of renting space in their gas lines by evaluating the incremental revenues they would earn relative to the incremental costs they would incur. Under COS/ROR, companies would also examine these incremental costs and revenues but would have to consider a host of related regulatory issues that would not arise under PBR. For example, the utility would have to consider whether any incremental revenues they earn would have to be given back to customers. The timing of such a "give back" would also be unpredictable, since the company can never know when it could be called in for a rate hearing. This unpredictability frustrates planning and analysis of project viability, since the installation could entail up-front costs while revenues would be generated over a multi-year period. There is a significant probability that the utility could be called in to "give back" these revenues before it has been compensated for its initial costs. It would also not be possible to finesse the regulatory issues by undertaking this activity through an unregulated subsidiary, since the project necessarily uses utility infrastructure. Under PBR, however, there are fewer regulatory concerns or unknowns, since the company's allowed prices

[2] Weisman, D. and J. Pfeifenberger, "Efficiency as a Discovery Process: Why Enhanced Incentives Outperform Regulatory Mandates," *Electricity Journal*, January/February 2003, 55-62.

would be set for a known, multi-year period by an external formula rather than on its own costs or revenues. It is therefore more likely that such a project (if deemed to be commercially viable) will be pursued under PBR than COS/ROR.

In sum, the Company's PBR proposal is superior to COS/ROR in promoting X efficiency, allocative efficiency, dynamic efficiency, innovation and new services, and reducing regulatory burdens. As the Department has indicated, all of these benefits help to promote its traditional goal of least cost energy service. Bay State is also subject to a comprehensive service quality incentive (SQI), implemented pursuant to a statewide generic proceeding on service quality regulation. This SQI creates appropriate regulatory incentives to encourage safe and reliable service and penalizes the Company if the safety, reliability or quality of its services fall below established thresholds. Bay State agrees to comply with whatever modifications or revisions of this SQI are implemented during the proposed five-year term of the Company's PBR proposal, and this regulatory measure is focused on the goals of safe and reliable service. Bay State therefore believes that the combination of its PBR proposal and the SQI will achieve the Department's goals of safe, reliable, least cost energy service more effectively than COS/ROR regulation.

Bay State's PBR proposal has also been crafted to be consistent with Department precedent. With the exception of the plan term, it is essentially identical to the PBR plan approved for Boston Gas in DTE 03-40, which satisfied the Department's standard of review for incentive ratemaking. However, as explained in the response to DTE 4-38, Bay State's proposed five-year plan term remains consistent with Department precedent for distributors that are implementing index-based PBR for the first time. In DTE 03-40, the Department also concluded "that Boston Gas' operation under its previous PBR plan may have contributed to constraining O&M cost growth to some extent, thus benefiting ratepayers" (DTE 03-40 at 471). As explained in the response to DTE 4-27, the evidence is that PBR contributed to constraining O&M cost growth for Bay State at least as strongly as for Boston Gas, thereby creating at least as many benefits for ratepayers. The Company's proposed PBR plan creates equally strong incentives to control costs as the expired rate freeze and, by allowing pricing flexibility for the first time, is more likely than the expired rate freeze to satisfy the Department's objectives of more efficient pricing and elimination of cross-subsidies.

All of these factors create benefits for customers compared with COS/ROR. Compared with PBR, cost of service regulation will impose incremental administrative burdens and regulatory costs, reduce the ability and incentive to manage costs effectively, reduce the ability and incentive to price efficiently and thereby maximize output growth, and reduce the feasibility of longer-term initiatives that can benefit customers.

Because PBR allows and encourages the Company to improve its efficiency vis-à-vis cost of service regulation, rates will be lower under PBR compared with COS/ROR. Rates therefore remain just and reasonable under the Company's proposal since the alternative is more rapid price growth.

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Date: June 30, 2005

Responsible: Lawrence R. Kaufmann, Consultant (PBR)

DTE-4-43 Refer to Exh. BSG/LRK-1, at 11-12. Please demonstrate that the proposed PBR plan meets the Department's standard of review for incentive ratemaking.

Response: Please see the response to DTE-4-42.

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Date: June 30, 2005

Responsible: Lawrence R. Kaufmann, Consultant (PBR)

DTE-4-49 Refer to Exh. BSG/LRK-1, at 15. Please explain whether the proposed Z-factor in the Company's price cap formula applies to both exogenous cost increases <u>and</u> exogenous cost decreases as a result of (1) changes in tax laws, accounting principles, and regulatory, judicial, or legislative actions uniquely affecting the local gas distribution industry, and (2) cost changes that are beyond the Company's control and not accounted for in the GDP-PI term used in the Company's PBR formula.

Response: Yes. The proposed Z factor refers to all exogenous cost *changes*, whether positive or negative, that satisfy the stated criteria in BSG/LRK-1 at 15.

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Date: June 30, 2005

Responsible: Lawrence R. Kaufmann, Consultant (PBR)

DTE-4-50 Refer to Exh. BSG/LRK-1, at 16. How will the Company treat price-cap increases greater than the rate of inflation because of the recovery of exogenous costs?

Response: Overall growth in the Company's prices will be restricted by the growth in the price cap index (PCI). The Company proposes that the annual change in the PCI will be equal to measured GDP-PI inflation, minus 0.41%, plus or minus any Z-factored cost that the Department allows the Company to recover. Therefore, the Department ultimate determines whether exogenous cost recovery leads to "price cap increases greater than the rate of inflation." This can only occur if the Z-factor adjustment approved by the Department leads to a price increase of more than 0.41%.

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Date: June 30, 2005

Responsible: Lawrence R. Kaufmann, Consultant (PBR)

DTE-4-52 Refer to Exh. BSG/LRK-1, at 18. Will the Company adjust its service quality plan to incorporate any changes or modifications to the Department's service quality guidelines set forth in D.T.E. 99-84 during the term of the PBR plan? Please explain.

Response: Yes. During the term of the PBR plan, the Company will comply with all changes and modifications the Department may make to the service quality guidelines set forth in D.T.E. 99-84.

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RESPONSE OF BAY STATE GAS COMPANY TO THE
FIFTH SET OF INFORMATION REQUESTS FROM THE D.T.E.
D. T. E. 05-27

Date: June 30, 2005

Responsible: John Skirtich, Consultant (Revenue Requirements)

DTE-5-26 Refer to Exh. BSG/JES-1, at 35. Please provide all communications, documents and workpapers associated with the $2.4 million sale/lease back of Itron equipment that occurred in December 2004.

Response: Please see Attachment DTE-5-26.

Attachment DTE –5-26

Project

2004 BSG Itron AMR sale/leaseback with Fleet Capital Corporation

Net Book Value of Equipment: $2,536,278
Term: 107 months
Rental Payments: 1 thru 53 - $25,842.25
54 thru 107 - $30,336.00
Early Termination: Buyout at 96 months - cost $464,900
Implied Lease Rate: 3.59%
Implied Rate with Early Termination: 4.22%
Cumulative NPV of Cash Flow (Lease Option): ($1,447,289)
Cumulative NPV of Cash Flow (Buy Option): ($1,749,072)

Summary

This is the last year of a 5-year, $20 million agreement with Fleet Capital Corporation for the sale and leaseback of Itron AMR devices in Massachusetts. The actual five-year total will come to $20,115,781. The net impact of the sale of these assets has been included in the 2004 Capital Budget, and the rental payments are included in the current 5-year operating plan.

The attached analyses compare the net present value of leasing to that of purchasing the equipment, using an incremental borrowing rate of 5.8%, and assuming the early purchase option is exercised. The analysis indicates that the benefit of leasing over purchasing is $301,783. The implied lease rate, assuming early buyout is 4.22%.

The terms of this lease meet FASB 13 requirements for classification as an operating lease.

It is requested that this transaction be approved and documents executed prior to the Christmas break in order to guarantee receipt of funds before year-end.

Attachment DTE-5-26

Purchase Option Based on 12 year Economic Life w/7 yr Accelerated Depreciation

Cumulative NPV ($1,749,072)

Income Statement	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20
Revenue Impact		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O&M Impact		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Property Tax	1.89%	($30,495)	($26,500)	($22,506)	($18,511)	($14,516)	($10,522)	($6,527)	($2,532)	$1,462	$5,457	$9,452	$13,446	$0	$0	$0	$0	$0	$0	$0	$0
Book Depreciation (12 years)		($211,357)	($211,357)	($211,357)	($211,357)	($211,357)	($211,357)	($211,357)	($211,357)	($211,357)	($211,357)	($211,357)	($211,357)	$0	$0	$0	$0	$0	$0	$0	$0
Lease Expense		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
EBIT		($241,851)	($237,857)	($233,862)	($229,867)	($225,873)	($221,878)	($217,883)	($213,889)	($209,894)	($205,900)	($201,905)	($197,910)	$0	$0	$0	$0	$0	$0	$0	$0
Income Tax Expense	40.53%	$98,010	$96,391	$94,773	$93,154	$91,535	$89,916	$88,297	$86,678	$85,060	$83,441	$81,822	$80,203	$0	$0	$0	$0	$0	$0	$0	$0
NOPAT		($143,841)	($141,465)	($139,089)	($136,714)	($134,338)	($131,962)	($129,586)	($127,210)	($124,835)	($122,459)	($120,083)	($117,707)	$0	$0	$0	$0	$0	$0	$0	$0

Cash Flow	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20
NOPAT		($143,841)	($141,465)	($139,089)	($136,714)	($134,338)	($131,962)	($129,586)	($127,210)	($124,835)	($122,459)	($120,083)	($117,707)	$0	$0	$0	$0	$0	$0	$0	$0
Add Deferred Taxes		$61,224	$166,063	$94,115	$42,723	$6,133	$6,030	$6,133	($39,811)	($85,652)	($85,652)	($85,652)	($85,652)	$0	$0	$0	$0	$0	$0	$0	$0
Add Book Depreciation		$211,357	$211,357	$211,357	$211,357	$211,357	$211,357	$211,357	$211,357	$211,357	$211,357	$211,357	$211,357	$0	$0	$0	$0	$0	$0	$0	$0
GROSS Cash Flow		$128,740	$235,954	$166,382	$117,366	$83,151	$85,424	$87,903	$44,335	$870	$3,246	$5,621	$7,997	$0	$0	$0	$0	$0	$0	$0	$0
Less: Capital Expenditures	$2,536,278	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
NET Cash Flow	**($2,536,278)**	**$128,740**	**$235,954**	**$166,382**	**$117,366**	**$83,151**	**$85,424**	**$87,903**	**$44,335**	**$870**	**$3,246**	**$5,621**	**$7,997**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Cumulative NPV @	**5.80%**	**($2,414,596)**	**($2,203,803)**	**($2,063,312)**	**($1,969,642)**	**($1,906,917)**	**($1,846,010)**	**($1,786,771)**	**($1,758,532)**	**($1,758,008)**	**($1,756,161)**	**($1,753,138)**	**($1,749,072)**	**($1,749,072)**	**($1,749,072)**	**($1,749,072)**	**($1,749,072)**	**($1,749,072)**	**($1,749,072)**	**($1,749,072)**	**($1,749,072)**

Deferred Tax Computation	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20
Plant	$1,613,481	$1,613,481	$1,402,125	$1,190,768	$979,412	$768,055	$556,699	$345,342	$133,986	($77,371)	($288,728)	($500,084)	($711,441)	$0	$0	$0	$0	$0	$0	$0	$0
Tax depreciation (7 years)		$362,434	$621,134	$443,595	$316,781	$226,490	$226,236	$226,490	$113,118	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Book depreciation		$211,357	$211,357	$211,357	$211,357	$211,357	$211,357	$211,357	$211,357	$211,357	$211,357	$211,357	$211,357	$0	$0	$0	$0	$0	$0	$0	$0
Deferred taxes		$61,224	$166,063	$94,115	$42,723	$6,133	$6,030	$6,133	($39,811)	($85,652)	($85,652)	($85,652)	($85,652)	$0	$0	$0	$0	$0	$0	$0	$0

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8
7 Year MACRS Factor	14.29%	24.49%	17.49%	12.49%	8.93%	8.92%	8.93%	4.46%
Tax Depreciation	$362,434	$621,134	$443,595	$316,781	$226,490	$226,236	$226,490	$113,118

Lease Terms

Acquisition Cost:	$ 2,536,278
Payment Terms 53 Months @:	0.01018906
Then 54 Months @:	0.01196083
Buyout after 96 Months @:	18.330%
Buyout Amount:	$ 464,900
Implicit Lease Rate:	3.63%
Lessee Incremental Borrowing Rate:	5.800%
NPV of Lease Payments (after deduction of 2.13% executory fees):	$2,244,225
As Percent of Acquisition Cost:	88.48%
Economic Life of Asset(months):	144
Lease Term (months):	107
Lease Term as % of Life of Asset:	74.31%

Lease Option Based on 12 year Economic Life w/7 yr Accelerated Depreciation

Cumulative NPV ($1,447,289)

Income Statement	2003 Year 0	2004 Year 1	2005 Year 2	2006 Year 3	2007 Year 4	2008 Year 5	2009 Year 6	2010 Year 7	2011 Year 8	2012 Year 9	2013 Year 10
Revenue From Rate Increase		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Estimated O&M Savings		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Property Tax		$0	$0	$0	$0	$0	$0	$0	$0	($8,787)	($8,054)
Book Depreciation (12 year)		$0	$0	$0	$0	$0	$0	$0	$0	($38,742)	($38,742)
Lease Expense		($310,107)	($310,107)	($310,107)	($310,107)	($341,563)	($364,032)	($364,032)	($364,032)	$0	$0
EBIT		($310,107)	($310,107)	($310,107)	($310,107)	($341,563)	($364,032)	($364,032)	($364,032)	($47,528)	($46,796)
Income Tax Expense	40.53%	$125,671	$125,671	$125,671	$125,671	$138,419	$147,524	$147,524	$147,524	$19,261	$18,964
NOPAT		($184,436)	($184,436)	($184,436)	($184,436)	($203,145)	($216,508)	($216,508)	($216,508)	($28,267)	($27,832)
Cash Flow	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
NOPAT		($184,436)	($184,436)	($184,436)	($184,436)	($203,145)	($216,508)	($216,508)	($216,508)	($28,267)	($27,832)
Add Deferred Taxes		$0	$0	$0	$0	$0	$0	$0	$0	$11,222	$30,439
Add Book Depreciation		$0	$0	$0	$0	$0	$0	$0	$0	$38,742	$38,742
GROSS Cash Flow		($184,436)	($184,436)	($184,436)	($184,436)	($203,145)	($216,508)	($216,508)	($216,508)	$21,697	$41,349
Less: Capital Expenditures	$0	$0	$0	$0	$0	$0	$0	$0	$ 464,900	$0	$0
NET Cash Flow	$0	($184,436)	($184,436)	($184,436)	($184,436)	($203,145)	($216,508)	($216,508)	($681,408)	$21,697	$41,349
Cumulative NPV @	5.81%	($174,309)	($339,047)	($494,739)	($641,882)	($795,051)	($949,333)	($1,095,143)	($1,528,847)	($1,515,796)	($1,492,289)
Deferred Tax Computation	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Plant	$0	$0	$0	$0	$0	$0	$0	$0	$ 464,900	$464,900	$426,158
Tax depreciation (7 years)		$0	$0	$0	$0	$0	$0	$0	$0	$66,434	$113,854
Book depreciation		$0	$0	$0	$0	$0	$0	$0	$0	$38,742	$38,742
Deferred taxes		$0	$0	$0	$0	$0	$0	$0	$0	$11,222	$30,439
7 Year MACRS Factor										14.29%	24.49%
Tax Depreciation										$66,434	$113,854
Lease Payments:	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Lease Payments on:	$(2,536,278)	$310,107	$310,107	$310,107	$310,107	$341,563	$364,032	$364,032	$364,032	$ 364,032	$0
Executory Fees @:	2.13%	$6,605	$6,605	$6,605	$6,605	$7,275	$7,754	$7,754	$7,754	$7,754	$0
Lease Payments Less Exec Fees:		$303,502	$303,502	$303,502	$303,502	$334,288	$356,278	$356,278	$356,278	$356,278	$0

Income Statement	2014 Year 11	2015 Year 12	2016 Year 13	2017 Year 14	2018 Year 15	2019 Year 16	2020 Year 17	2021 Year 18	2022 Year 19	2023 Year 20
Revenue From Rate Increase	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Estimated O&M Savings	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Property Tax	($7,322)	($6,590)	($5,858)	($5,126)	($4,393)	($3,661)	($2,929)	($2,197)	($1,464)	($732)
Book Depreciation (12 year)	($38,742)	($38,742)	($38,742)	($38,742)	($38,742)	($38,742)	($38,742)	($38,742)	($38,742)	($38,742)
Lease Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
EBIT	($46,064)	($45,332)	($44,599)	($43,867)	($43,135)	($42,403)	($41,671)	($40,938)	($40,206)	($39,474)
Income Tax Expense	$18,667	$18,371	$18,074	$17,777	$17,480	$17,184	$16,887	$16,590	$16,294	$15,997
NOPAT	($27,396)	($26,961)	($26,525)	($26,090)	($25,655)	($25,219)	($24,784)	($24,348)	($23,913)	($23,477)
Cash Flow	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20
NOPAT	($27,396)	($26,961)	($26,525)	($26,090)	($25,655)	($25,219)	($24,784)	($24,348)	($23,913)	($23,477)
Add Deferred Taxes	$17,251	$7,831	$1,124	$1,105	$1,124	($7,297)	($15,700)	($15,700)	($15,700)	($15,700)
Add Book Depreciation	$38,742	$38,742	$38,742	$38,742	$38,742	$38,742	$38,742	$38,742	$38,742	$38,742
GROSS Cash Flow	$28,596	$19,612	$13,340	$13,757	$14,211	$6,225	($1,742)	($1,306)	($871)	($435)
Less: Capital Expenditures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
NET Cash Flow	$28,596	$19,612	$13,340	$13,757	$14,211	$6,225	($1,742)	($1,306)	($871)	($435)
Cumulative NPV @	($1,476,924)	($1,466,965)	($1,460,563)	($1,454,324)	($1,448,232)	($1,445,710)	($1,446,377)	($1,446,850)	($1,447,148)	($1,447,289)
Deferred Tax Computation	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20
Plant	$387,416	$348,675	$309,933	$271,192	$232,450	$193,708	$154,967	$116,225	$77,483	$38,742
Tax depreciation (7 years)	$81,311	$58,066	$41,516	$41,469	$41,516	$20,735	$0	$0	$0	$0
Book depreciation	$38,742	$38,742	$38,742	$38,742	$38,742	$38,742	$38,742	$38,742	$38,742	$38,742
Deferred taxes	$17,251	$7,831	$1,124	$1,105	$1,124	($7,297)	($15,700)	($15,700)	($15,700)	($15,700)
7 Year MACRS Factor	17.49%	12.49%	8.93%	8.92%	8.93%	4.46%	0.00%			
Tax Depreciation	$81,311	$58,066	$41,516	$41,469	$41,516	$20,735	$0			
Lease Payments:	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20
Lease Payments on:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Executory Fees @:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Lease Payments Less Exec Fees:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
FIFTEENTH SET OF INFORMATION REQUESTS FROM THE D.T.E.
D. T. E. 05-27

Date: June 30, 2005

Responsible:

DTE-15-19 Refer to the Company's response to the Department's information request DTE 4-1. Please:

(a) discuss the differences, if any, in the definition and measurement of O&M expenses between the Boston Gas cost trend analysis in D.T.E. 03-40 and the Bay State cost trend analysis in the instant proceeding.
(b) discuss the comparability of the results of the two studies given any differences in the definition and measurement of O&M expenses between the two studies;
(c) explain why the Company eliminated pensions, transmission and storage O&M expenses from the Bay State econometric cost study when these costs were included in the Boston Gas econometric cost study in D.T.E. 03-40;
(d) explain why the Company did not include a "rate-freeze dummy" in the Bay State econometric cost model to estimate the independent effect of the rate-freeze on the Company's O&M costs similar to the "PBR dummy" in the Boston Gas econometric cost model.

Response:

(a) There are no known differences between the definition and measurement of O&M expenses in the Boston Gas and Bay State cost trend analyses.

(b) Given the answer to (a), I believe the cost trend analyses are comparable for Boston Gas and Bay State.

(c) Pensions were eliminated from O&M costs in the Bay State econometric study because these expenses are volatile, largely beyond the control of utility managers and, as approved in DTE 03-40 and proposed by Bay State in this proceeding, not subject to the PBR mechanism. Transmission and storage expenses were eliminated from O&M expenses in order to respond to the Department's comments in DTE 03-40, where one of the concerns noted for the econometric cost model was that "the cost study did not distinguish between distribution and non-distribution labor and O&M expenses, but assumed that all costs were distribution costs" (DTE 03-40 at 485).

(d) The econometric cost model did not include a “rate freeze dummy” because this variable was not statistically significant.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
NINETEENTH SET OF INFORMATION REQUESTS FROM THE D.T.E.
D. T. E. 05-27

Date: June 30, 2005

Responsible: Joseph A. Ferro, Manager Regulatory Policy

DTE-19-15 Refer to Exh. BSG/JAF-2, Sch. JAF 2-1, at 13-14, line 356. Please provide the cite to the COS Schedules where these values can be found.

Response: The COS Schedules that were linked to the rate design worksheet, Schedule JAF-2-1, were provided in electronic format in response to AG-7-5, AG-7-6, AG-7-7 and AG-7-11 (Confidential), in which the Company provided the AG and the Department with an electronic copy of the working linked spreadsheets for Schedule JAF-2-1, JAF-2-2, JAF-2-3, JAF-2-4, JAF-2-5 and JAF-2-10. The tab (worksheet) labeled “MAC” in Schedule JAF-2-1 contains the COS values shown on line 356. These values also were filed with Mr. Harrison’s testimony, Exhibit BSG/JLH-2, on line 13 of Schedule JLH-2-2, page 1.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
NINETEENTH SET OF INFORMATION REQUESTS FROM THE D.T.E.
D. T. E. 05-27

Date: June 30, 2005

Responsible: Joseph A. Ferro, Manager Regulatory Policy and
John E. Skirtich, Consultant (Revenue Requirements)

DTE-19-16 Refer to Exhibit BSG/JES-1, Schedule JES-5. Although a reference is given for line 1, please confirm the source of the per-books cost of gas appearing in column 1, $323,863,512, and explain any discrepancy between this figure and the per-books cost of gas appearing in Schedule JAF-1-1.

Response: The revenues presented in column 2, lines 2-5, of Schedule JAF-1-1, labeled “GAF Per Books”, which total $323,692,472, represent the product of actual billing month sales volumes and actual GAF rates. While, the per-books cost of gas appearing in Schedule JES-5, column 1, of $323,863,512 reflects, in addition to the product of actual billing month sales volumes and actual GAFs, unbilled gas cost revenues and the cost of gas associated with interruptible and off-system sales.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
NINETEENTH SET OF INFORMATION REQUESTS FROM THE D.T.E.
D. T. E. 05-27

Date: June 30, 2005

Responsible: Joseph A. Ferro, Manager Regulatory Policy

DTE-19-17 Refer to Exhibit BSG/JAF-1, at 7. Please confirm that the billing-month use was weather normalized, as implied in Step 2, and then was weather normalized again after conversion to a calendar-month basis, as implied in Step 4.

Response: Billing-month use was weather normalized as stated on page 7 of Exh. BSG/JAF-1, and as shown on Sheet 1, columns 1-11 of each page 1 of Schedule JAF-1-6. The Company, after converting actual (not weather normalized) billing month sales to calendar month sales, weather-normalized the calendar month volumes, as shown in columns 22-31 of Schedule JAF-1-6. The Company weather-normalized billing month volumes primarily for informational purposes, as this step was not essential to determining the test year (calendar month) billing determinants.

Please see Bay State's response to DTE-19-19 for an explanation of all steps taken to derive test year billing determinants.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
NINETEENTH SET OF INFORMATION REQUESTS FROM THE D.T.E.
D. T. E. 05-27

Date: June 30, 2005

Responsible: Joseph A. Ferro, Manager Regulatory Policy

DTE-19-18 Refer to Exhibit BSG/JAF-1, at 7. Please clarify if by “rate class” in Step 3, the Company is actually referring to the six “groups” identified in step 2.

Response: The term “rate class” used in Step 3 is correctly referring to rate classes. In Step 2, after weather normalizing and converting to calendar month by rate “groups”, the results are allocated back to each customer in the rate group” by the ratio of the total calendar month to billing month volumes of that rate group. Then, in Step 3, a bill frequency analysis is performed by accumulating the calendar month volumes of each customer by rate class.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
NINETEENTH SET OF INFORMATION REQUESTS FROM THE D.T.E.
D. T. E. 05-27

Date: June 30, 2005

Responsible: Joseph A. Ferro, Manager Regulatory Policy

DTE-19-19 Refer to Exhibit BSG/JAF-1, at 13, where it is stated that Step 2 "is to convert the billing month gas volumes to a calendar month basis," and also refer to page 15 of the same exhibit, where it is stated that Step 3 "is the conversion of billing month usage volumes to calendar month usage volumes. Please provide a new, detailed list of the steps actually taken, in the order actually taken, to determine test-year billing determinants.

Response: Pages 7 and 13 of Exh. BSG/JAF-1 more accurately states and references Step 2 – mainly, convert from billing month to calendar month volumes, while on page 15, Step 3 of the process is referred to as "previously identified as Step (2)." Confusion may have been created because on page 15 a sub-step of Step 2, aggregating billing month use into the six rate groupings, was considered as a separate Step (2). The steps taken to determine test-year billing determinants are as follows:

(1) Extract each customer's monthly billing use from the Company's Customer Information System (CIS);
    a. Any identifiable prior month billing adjustments were eliminated form the month in which they were invoiced and distributed back to the months in which they pertained,
    b. Although just for informational purposes, as the Department has been accustomed to reviewing weather normalization of billing month data, the actual billing month volumes were weather normalized, as shown in columns 1-11 of Schedule JAF-1-6.
(2) Convert from billing month volumes to calendar month volumes by:
    a. Aggregating billing month use into the six rate groupings (see page 7 of Exh. BSG/JAF-1,
    b. Deriving Temperature sensitive unbilled to convert from actual billing month to calendar month volumes, as shown in columns 12-21 of Schedule JAF-1-6.
(3) Accumulate, by rate class, calendar month gas volumes by head/tail block consumption levels by running a bill frequency analysis. Before running this bill frequency, actual calendar month volumes (from Step 2) are allocated to each customer in the rate group by the ratio of the total calendar month to billing month volumes of that rate group;
(4) Weather normalize calendar month volumes, as shown in columns 22-31 of Schedule JAF-1-6, and then assign these normalized volumes to each customer in the rate group by the ratio of the

normalized calendar month to actual calendar month volumes of that rate group.

(5) Perform a bill frequency analysis on weather normalized calendar month volumes by customer and accumulate by rate class.

Please see response to DTE-22-04.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
NINETEENTH SET OF INFORMATION REQUESTS FROM THE D.T.E.
D. T. E. 05-27

Date: June 30, 2005

Responsible: Joseph A. Ferro, Manager Regulatory Policy

DTE-19-20 Refer to exhibit BSG/JAF-1, at 35. Please indicate whether the pipeline refunds that were excluded from gas costs in column 2 of Schedule JAF-1-1, sheet 2, were included in column 2 Schedule JAF-1-1, sheet 1.

Response: The pipeline refunds were included in the "GAF Per Books" in column 2 of Schedule JAF-1-1, sheet 1, as they were also included in the "Per Books" revenue in column 1, sheet 1. Including the pipeline refunds in both these columns, cancels out these refunds and is consistent with presenting Annualized Delivery Service Revenue in both column 7 of sheet 1 and column 1 of sheet 2.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
NINETEENTH SET OF INFORMATION REQUESTS FROM THE D.T.E.
D. T. E. 05-27

Date: June 30, 2005

Responsible: James L. Harrison, Consultant (Cost Studies)

DTE-19-21 Refer to Exhibit BSG/JLH-1, at 4. Please explain what is meant by the phrase "development of indirect gas costs," and elaborate on how the development of these costs, as distinguished from direct gas costs, causes gas-cost allocation to impact the design of base rates.

Response: Indirect gas costs are established in the class cost of service study as the difference between total supply-related revenue requirements and direct gas costs (fuel and purchased gas expense). Supply-related bad debt expense is one of the major indirect gas costs. Prior to unbundling, indirect gas costs were recovered in base rates. Since unbundling, indirect gas costs have been recovered as part of supply rates and have been excluded from delivery rates. The computation of supply-related bad debt expense begins with each class's bad debt expense and multiplies that figure by the percentage of the class's revenue requirements related to supply. The nature of the allocations employed in the class cost of service study impact the percentage of each class's supply related revenue requirement to its total revenue requirement and therefore impact the allocation of indirect gas costs.

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Date: June 30, 2005

Responsible: Joseph A. Ferro, Manager Regulatory Policy

DTE-19-24 Refer to Schedule JLH-1-6, at 6. Please define the term "stranded production and storage."

Response: The term "stranded production and storage" is taken from Section 3 page 4 of the Company's September 14, 2004 Peak Period CGA filing, which shows an amount of $155,281. The term refers to the amount of production and storage costs, which is the portion of the revenue requirement of the LNG and LP plants related to the gas supply function determined in the Company's rate redesign case, D.P.U 95-52 / 95-104, that at that time was allocated to the Company's firm Off-system Sales class. This class of customers was comprised of natural gas utilities and municipalities who took a bundled supply service for their winter requirements under individual contracts. The contracts of all these customers expired several years ago, leaving the amount of production and storage costs allocated to this class unassigned.

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Date: June 30, 2005

Responsible: Danny G. Cote, General Manager

DTE-20-6 Please identify the number of leaks attributable to corrosion, which were identified, but not yet repaired, during the period 1985 to present, by class (i.e., Grade 1, 2, or 3) and type of main (i.e., cast and wrought iron, bare steel, unprotected coated steel, cathodically protected coated steel, and plastic).

Response: See Attachment DTE-20-6.

DTE 20-6

	Class			
Year	**1**	**2**	**3**	Total
1993	0	0	187	187
1994	0	0	139	139
1995	0	0	103	103
1996	0	0	100	100
1997	0	0	89	89
1998	0	0	186	186
1999	0	0	282	282
2000	0	0	391	391
2001	0	0	121	121
2002	0	0	224	224
2003	0	0	183	183
2004	0	0	119	119
2005	0	131	126	257
Total	0	131	2250	2381

Data from WOMS, job codes include LIMX, LISX, LRMX, LRSX only

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Date: June 30, 2005

Responsible: Joseph A. Ferro, Manager Regulatory Policy

DTE-7-11 Regarding the Company's proposed dual fuel tariff (Exh. BSG/JAF-3 at 3-6), please provide a list of all the Massachusetts LDCs that have implemented such a tariff.

Response: The Company is only aware of Commonwealth Gas Company (now NSTAR) implementing a similar dual fuel tariff, under which any customer with an alternative source of energy was subject to a minimum annual revenue requirement based on applying a fixed charge to estimated natural gas requirements.

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Date: June 30, 2005

Responsible: Joseph A. Ferro, Manager Regulatory Policy

DTE-7-12 In developing its proposed distribution rates, please discuss how Bay State has accounted for the consumption/throughput by dual fuel customers.

Response: The billing determinants used in developing the Company's distribution rates reflect the actual gas consumption of dual fuel customers, adjusted in the same manner and for the same conditions as for the usage of all other firm customers. Considering that it is quite uncertain of the effect that the dual fuel provision would have on the Company's throughput, any other adjustment to test year billing determinants would be unfounded. Please also see Bay State's response to AG-9-27.

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Date: June 30, 2005

Responsible: Joseph A. Ferro, Manager Regulatory Policy

DTE-7-13 Has the Company considered developing a dual fuel tariff that would entice rather than obligate dual fuel customers to prefer gas over alternative fuels?

Response: At a high level over the years the Company has considered a dual fuel tariff that could entice the use of natural gas over alternative fuels. However, based on input from Sales personnel and from customers, the only such tariff that could achieve this would be a flexible tariff that did not require a customer to commit for more than one year. Even if such a tariff were to be effective in enticing natural gas use and the Department would approve such a tariff, the year-to-year nature of the tariff would create similar potential distribution revenue volatility as under the current conditions of having no special dual fuel tariff provision. That is, some years customers would commit to using natural gas and other years they would not and switch back to their alternate fuel. At least, however, during the year of no service the customer should not have firm service available while not paying for it. Also, there would be no assurance to the customer that distribution capacity would be available in future years.

Although Sales personnel has felt that a flexible year-to-year tariff would have the best chance of enticing the use of natural gas, the Company has continually looked for the opportunity for special contract arrangements with dual fuel customers whose natural gas use has been at a minimum level due to having switched to an alternate fuel over recent time, or customers who have indicated they will be switching to their alternative fuel. If such an opportunity were presented, the Company and Customer would establish a contractual Maximum Daily Quantity (MDQ) representing the Company's obligation to provide firm distribution service, on which the Company's long-run marginal costs would be determined to assess an appropriate minimum annual revenue requirement. The barrier to the special contract approach, in addition to non-competitiveness of natural gas, is the typical requirement of having the customer commit to more than one year, and the 30-day turn-around of the Department reviewing and approving the contract. Since natural gas prices are volatile, the agreed upon special distribution rate based on the then-current commodity prices may no longer be economic for the customer if by the time the contract is approved and the customer needs to commit to a gas supply, gas prices have increased.

The absence of special contract opportunities has lead the Company to believe that customers prefer having fuel-switching flexibility, while continuing to have firm service accessibility. Since, it has been quite difficult to extract an appropriate level of distribution revenue from customers who have a commensurate level of available firm distribution capacity, even at discounted distribution rates, the Company feels that a dual fuel special provision to tariff service is appropriate. Conversely, it is highly unlikely that a duel fuel tariff that recovers a sufficient level of distribution costs and avoids the year-to-year swings in natural gas service and associated distribution revenue can be developed to entice the use of natural gas rather than fuel switching.

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Date: June 30, 2005

Responsible: Joseph A. Ferro, Manager Regulatory Policy

DTE-7-14 Please refer to Exh. BSG/JAF-3 at 4, lines 19-21. Discuss how and when "...costs are shifted to other customers," who these other customers are, and when these other customers pay for these costs.

Response: If the Company allows customers who have firm distribution capacity rights to continue to fuel switch, the distribution revenue shortfall associated with the unanticipated reduction in throughput, or disproportionately low throughput, will eventually result in costs or revenue requirements to be charged to all other firm customers.

In the present, if dual fuel customers were using a greater volume of natural gas that is more in line with their equipment connected to the distribution system, the Company's revenue deficiency and associated rate proposal would likely have been less. Thus, all firm customers today pay for more of the cost of the distribution system than they otherwise would if there were no fuel switching. However this hypothetical of greater use from dual fuel customers, is not only non-quantifiable, but quite unrealistic, as customers have dual fuel equipment for that very reason of not having to use natural gas when it is not competitive with their alternate fuel. In essence, the disproportionate level of dual fuel customer throughput to the level of firm service available to them is a "normal" or representative test year level.

The Company's dual fuel provision in this instant proceeding will not likely create an increase in revenue that would eventually serve to lower rates to all other firm customers, but rather will weed out those customers who are not willing to commit to, or pay for, firm rights on the Company's distribution system at the level of their full natural gas requirements. (See response to AG-9-27.) Conversely, the proposed provision will hopefully result in other dual fuel customers to commit to a minimal level of natural gas service. Further, the proposed dual fuel provision will establish provisions (or rules) that should eventually create a fair allocation of costs (or revenue requirement) among all firm customers and avoid cost shifting. In addition, even in the somewhat likely event that dual fuel customers opt to discontinue firm service, the Company should be able to better utilize its distribution capacity for profitable growth opportunities that will benefit all firm customers in the long run with respect to holding down rates.

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Date: June 30, 2005

Responsible: Joseph A. Ferro, Manager Regulatory Policy

DTE-7-15 Please refer to Exh. BSG/JAF-3 at 5, lines 7-9. Discuss why the Company excluded the G/T 40 and G/T 50 classes from its proposed dual fuel tariff.

Response: The Company excluded the G/T-40 and G/T-50 classes, whose annual use is less than 5,000 therms, from its proposed dual fuel tariff for three reasons, related to both the low use nature of the classes and the relatively significant number of customers. These three reasons are as follows:

(1) Based on Sales personnel experience, generally low use customers find investments in dual fuel equipment to be uneconomic; thus it is believed that there are not many customers in these classes whose use is primarily dual fuel.
(2) Administratively, it would be quite difficult, even unrealistic, to identify and analyze any low-use customers in these two customer classes comprising approximately 19,000 customers, who might currently have dual fuel capabilities.
(3) The Company feels that the full dual fuel gas capabilities of these low use customers represent a relatively insignificant gas requirement that would create any cost shifting or inefficient reservation of capacity to serve these customers.

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Date: June 30, 2005

Responsible: Joseph A. Ferro, Manager Regulatory Policy

DTE-7-16 Please discuss whether the proposed dual fuel tariff will provide disincentives for large C&I customers willing to expand or move operations to Massachusetts in general and Bay State's territory in particular.

Response: For a large C&I customer with dual fuel capability, and with the operational plan of fuel switching while having 365-day access to an LDC's distribution system, the proposed dual fuel tariff could provide a disincentive to expand or move operations into Bay State's service territory. It is the Company's understanding, though, that much more significant conditions would provide that disincentive, such as access to markets, labor costs, cost of transportation of product or raw materials to and from an operating plant and taxes.

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Date: June 30, 2005

Responsible: Joseph A. Ferro, Manager Regulatory Policy

DTE-7-17 Please discuss whether the Company's reasoning behind dual fuels customers is applicable to C&I customers who chose to suspend operations (and therefore gas consumption) as a result of high gas prices.

Response: The Company believes that, irrespective of the reason why dual fuel customers have switched to their alternate fuel or even how many have switched, a dual fuel tariff provision of some form is appropriate for establishing guidelines to allow for a fair assignment of cost responsibility and optimal use and planning of the Company's distribution system. Certainly gas prices in relation to oil prices must be a significant factor as to a customer's decision to fuel switch.

The Company does not believe that any of its dual fuel customers who may not be using natural gas have suspended operations, but rather have switched to their alternate fuel.

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Date: June 30, 2005

Responsible: Joseph A. Ferro, Manager Regulatory Policy

DTE-7-18 Regarding the Company's proposed dual fuel tariff, please discuss the circumstances under which Bay State can enter a customer's premises to inspect a customer's equipment.

Response: The Company is reliant on the cooperation of the customer for it to enter the customer's premises to inspect a customer's equipment. In general, the Company works with these medium and high annual use C&I customers to assess their potential and projected energy needs, especially as operational, pricing or regulatory developments arise that could affect the customer. The Company typically attempts to explain to the customer the economics of using natural gas under all options available. Considering this relationship, the Company anticipates that it would be able to enter a customer's premises and have access to the customer's natural gas equipment, upon request and at the customer's convenience.

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RESPONSE OF BAY STATE GAS COMPANY TO THE
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Date: June 30, 2005

Responsible: John E. Skirtich, Consultant (Revenue Requirements)

DTE 22-1 Refer to Exh. BSG/JES-1, Sch. JES-5. Although a reference is given for line 1, please confirm the source of the per-books cost of gas appearing in column 1, $323,863,512, and explain any discrepancy between this figure and the per-books cost of gas appearing in Sch. JAF-1-1.

Response: The gas cost of $323,863,512 in Exh. BSG-JES-1, SCH. JES-5 are the per book gas cost. Please see Bay State's response to DTE-6-3 for the development of the cost. The gas costs of $307,478,651 appearing on Sch. JAF-1-1 are not per book gas costs. They are gas costs based on rates in effect during the test year and applying them to actual calendar year volumes, normalized for weather and adjusted for physical flow, and leap year.

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Date: June 30, 2005

Responsible: Joseph A. Ferro, Manager Regulatory Policy

DTE-22-2 Refer to Exh. BSG/JAF-1, at 7. Please confirm that the billing-month use was weather normalized, as implied in Step 2, and then was weather normalized again after conversion to a calendar-month basis, as implied in Step 4.

Response: Billing-month use was weather normalized as stated on page 7 of Exh. BSG/JAF-1, and as shown on Sheet 1, columns 1-11 of each page 1 of Schedule JAF-1-7.

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Date: June 30, 2005

Responsible: Joseph A. Ferro, Manager Regulatory Policy

DTE-22-3 Refer to Exh. BSG/JAF-1, at 7. Please clarify if the term “rate class” used in Step 3 is actually referring to the six “groups” identified in step 2.

Response: The term “rate class” used in Step 3 is correctly referring to rate classes. In Step 2, after weather normalizing and converting to calendar month by rate “groups”, the results are allocated back to each customer in the rate group” by the ratio of the total calendar month to billing month volumes of that rate group. Then, in Step 3, a bill frequency analysis is performed by accumulating the calendar month volumes of each customer by rate class.

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Date: June 30, 2005

Responsible: Joseph A. Ferro, Manager Regulatory Policy

DTE-22-4 Refer to Exh. BSG/JAF-1, at 13, where it is stated that Step 2 "is to convert the billing month gas volumes to a calendar month basis," and also refer to page 15 of the same exhibit, where it is stated that Step 3 "is the conversion of billing month usage volumes to calendar month usage volumes. Please provide a new, detailed list of the steps actually taken, in the order actually taken, to determine test-year billing determinants.

Response: Pages 7 and 13 of Exh. BSG/JAF-1 more accurately states and references Step 2 – mainly, convert from billing month to calendar month volumes, while on page 15, Step 3 of the process is referred to as "previously identified as Step (2)." Confusion may have been created because on page 15 a sub-step of Step 2, aggregating billing month use into the six rate groupings, was considered as a separate Step (2). The steps taken to determine test-year billing determinants are as follows:

(1) Extract each customer's monthly billing use from the Company's Customer Information System (CIS);
    a. Any identifiable prior month billing adjustments were eliminated form the month in which they were invoiced and distributed back to the months in which they pertained,
    b. Although just for informational purposes, as the Department has been accustomed to reviewing weather normalization of billing month data, the actual billing month volumes were weather normalized, as shown in columns 1-11 of Schedule JAF-1-6.
(2) Convert from billing month volumes to calendar month volumes by:
    a. Aggregating billing month use into the six rate groupings (see page 7 of Exh. BSG/JAF-1,
    b. Deriving Temperature sensitive unbilled to convert from actual billing month to calendar month volumes, as shown in columns 12-21 of Schedule JAF-1-6.
(3) Accumulate, by rate class, calendar month gas volumes by head/tail block consumption levels by running a bill frequency analysis. Before running this bill frequency, actual calendar month volumes (from Step 2) are allocated to each customer in the rate group by the ratio of the total calendar month to billing month volumes of that rate group;
(4) Weather normalize calendar month volumes, as shown in columns 22-31 of Schedule JAF-1-6, and then assign these normalized volumes to each customer in the rate group by the ratio of the

normalized calendar month to actual calendar month volumes of that rate group.

(5) Perform a bill frequency analysis on weather normalized calendar month volumes by customer and accumulate by rate class.

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Responsible: Joseph A. Ferro, Manager Regulatory Policy

DTE-22-5 Refer to Exh. BSG/JAF-1, at 35. Please indicate whether the pipeline refunds that were excluded from gas costs in column 2 of Sch. JAF-1-1, sheet 2, were included in column 2 of Sch. JAF-1-1, sheet 1.

Response: Please see response to DTE-19-20.

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Date: June 30, 2005

Responsible: James L. Harrison, Consultant (Cost Studies)

DTE-22-6 Refer to Exh. BSG/JLH-1, at 4. Please explain what is meant by the phrase “development of indirect gas costs,” and elaborate on how the development of these costs, as distinguished from direct gas costs, causes gas-cost allocation to affect the design of base rates.

Response: Please see Bay State’s response to DTE-19-21.

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Date: June 30, 2005

Responsible: James L. Harrison, Consultant (Cost Studies)

DTE-22-7 Refer to Exh. BSG/JLH-1, at 5. Please (i) explain how the Company's proposed revenue deficiency would change if indirect gas costs were not subtracted from the test year allowed revenue requirements and from test-year annualized revenue (see also, Exh. BSG/JES-1, Sch. JES-4) and (ii) comment on the usefulness of such an exercise in evaluating the Company's need for rate relief.

Response: Please see Bay State's response to DTE-19-22.

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Date: June 30, 2005

Responsible: James L. Harrison, Consultant (Cost Studies)

DTE-22-8 Refer to Exh. BSG/JLH-1, at 4. Please clarify what is meant by the term "manufactured production."

Response: Please see the Company's response to DTE-19-23.

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Date: June 30, 2005

Responsible: James L. Harrison, Consultant (Cost Studies)

DTE-22-9 Refer to Exh. BSG/JLH-1, Sch. JLH-1-6, at 6. Please define the term "stranded production and storage."

Response: Please see the Company's response to DTE-19-24.

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Date: June 30, 2005

Responsible: James L. Harrison, Consultant (Cost Studies)

DTE-22-10 Refer to Exh. BSG/JLH-1, at 6, lines 10-12. Please explain the rationale, under the Market-Based Allocation method, for accumulating base-load (i.e., high-load-factor) supply costs of commodity, capacity, and associated transportation and assigning them to the winter period, rather than assigning them to the entire year.

Response: Please see the Company's response to DTE-19-25.

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Date: June 30, 2005

Responsible: James L. Harrison, Consultant (Cost Studies)

DTE-22-11 Refer to Exh. BSG/JLH-1, at 5, lines 19-21, and at 8, lines 19-20.

(A) Considering that under the MBA, the Company would assign the least-cost capacity and commodity costs to base-load use, and under the SMBA, the Company would assign average capacity and commodity costs to base-load use, is it fair to deduce that the SMBA method results in higher costs being assigned to base use than does the MBA method?

Response: Please see the Company's response to DTE-19-26.